TECHNICAL REVIEW DOCUMENT
For
RENEWAL OF OPERATING PERMIT 96OPBO174

University of Colorado at Boulder
Williams Village
Boulder County
Source ID 0130019

Prepared by Blue Parish
November 2009 & January - March 2010

I. Purpose

This document establishes the basis for decisions made regarding the applicable requirements, emission factors, monitoring plan and compliance status of emission units covered by the renewed Operating Permit for the Williams Village facility. The previous Operating Permit for this facility was originally issued on December 1, 1998, was renewed on August 1, 2003 and was last revised on June 16, 2005. The permit expired on August 1, 2008; however, since a timely and complete renewal application was submitted, under Colorado Regulation No. 3, Part C, Section IV.C all of the terms and conditions of the existing permit shall not expire until the renewal operating permit is issued and any previously extended permit shield continues in full force and operation.

This document is designed for reference during the review of the proposed permit by the EPA, the public, and other interested parties. The conclusions made in this report are based on information provided in the renewal application submitted on July 27, 2007, additional information submitted on January 16, 2009, December 29, 2009, January 7, 2010 and February 24, 2010, comments on the draft permit submitted on March 25, 2010, previous inspection reports and various email correspondence, as well as telephone conversations with the applicant's consultant. Please note that copies of the Technical Review Document for the original permit and previous renewals and any Technical Review Documents associated with subsequent modifications may be found in the Division files as well as on the Division website at http://www.cdphe.state.co.us/ap/Titlev.html. This narrative is intended only as an adjunct for the reviewer and has no legal standing.

Any revisions made to the underlying construction permits associated with this facility made in conjunction with the processing of this operating permit application have been reviewed in accordance with the requirements of Regulation No. 3, Part B, Construction Permits, and have been found to meet all applicable substantive and procedural requirements. This operating permit incorporates and shall be considered to be a combined construction/operating permit for any such revision, and the permittee shall be allowed to operate under the revised conditions upon issuance of this operating permit without applying for a revision to this permit or for an additional or revised construction permit.

II. Description of Source

The University of Colorado at Boulder (CU) consists of a Power House, a service building, a heating plant for a dormitory known as Williams Village, and miscellaneous insignificant activities around campus. CU requested separate Operating Permits for the Power House and the heating plant for Williams Village. The service building is classified as an insignificant source of emissions. The heating plant at Williams Village generates steam for use in heating and air conditioning using two water tube boilers. The boilers have the capability to fire either natural gas or No. 2 fuel oil.

The facility is located at 600 30th Street in Boulder, Colorado. This facility is located in the Denver Metro Area. The Denver Metro Area is classified as attainment/maintenance for particulate matter less than 10 microns in diameter (PM10) and carbon monoxide (CO). Under that classification, all SIP-approved requirements for PM10 and CO will continue to apply in order to prevent backsliding under the provisions of Section 110(l) of the Federal Clean Air Act. The Denver Metro Area is classified as non-attainment for ozone and is part of the 8-hr Ozone Control Area as defined in Regulation No. 7, Section II.A.1. There are no affected states within 50 miles of the plant. The Federal Class I designated areas within 100 kilometers of the plant are Rocky Mountain National Park, Rawah Wilderness Area, and Eagle's Nest Wilderness Area.

The Power House and the Williams Village heating plant are categorized as a single Non-attainment New Source Review (NANSR) major stationary source (Potential to Emit of NOx $\geq$ 100 Tons/Year). Future modifications at this facility resulting in a significant net emissions increase (see Reg 3, Part D, Sections II.A.26 and 42) for VOC or NOx or a modification which is major by itself (Potential to Emit of $\geq$ 100 TPY of either VOC or NOx) may result in the application of the NANSR review requirements.

This facility is categorized as a Prevention of Significant Deterioration (PSD) major stationary source (Potential to Emit > 100 Tons/Year for NO_x, CO and SO_2). Future modifications at this facility resulting in a significant net emissions increase (see Reg 3, Part D, Sections II.A.26 and 42) or a modification which is major by itself (Potential to Emit of $\geq$ 100 TPY) for any pollutant listed in Regulation No. 3, Part D, Section II.A.42 for which the area is in attainment or attainment/maintenance may result in the application of the PSD review requirements

Emissions (in tons/yr) at Williams Village are as follows:

Pollutant	Potential to Emit (tpy)	Actual Emissions (tpy)
NOx	43.0	2.63
CO	27.8	2.19
VOC	1.8	0.14
SO_2	47.0	0.02
PM	8.5	0.20
PM_{10}	4.2	0.20
Total Hazardous Air Pollutants (HAPs)	0.1	Below APEN Thresholds
Highest Single HAP (Formaldehyde)	0.1	Below APEN Thresholds

PTE for SO_2 and NO_x are based on permit limits. PTE for other criteria pollutants and HAPs are based on AP-42 factors and the maximum assumed fuel use (see Attachment 1 for details). Actual emissions are from an APEN received on March 29, 2007.

Emissions (in tons/yr) for the Power House and Williams Village locations combined are as follows:

Pollutant	TOTAL Potential to Emit (tpy)	Actual Emissions (tpy) – Power House	Actual Emissions (tpy) – Williams Village
NOx	Less than 293	232.7	2.63
CO	117.8	41.1	2.19
VOC	64.4	3.45	0.14
SO_2	103.7	3.45	0.02
PM	32.7	8.25	0.20
PM_{10}	30.1	8.25	0.20
Total Hazardous Air Pollutants (HAPs)	1.3	Not reported	Below APEN Thresholds
Highest Single HAP (Formaldehyde)	1.1	Not reported	Below APEN Thresholds

Actual emissions for the Power House are from the Division's Inventory System for the year 2009. See Attachment 1 for details on Power House emission calculations.

Applicable Requirements

Prevention of Significant Deterioration (PSD) Thresholds

The original permit and subsequent renewal noted that the facility was subject to a 250 ton per year major source threshold for PSD applicability. However, EPA has concluded that "the definition of fossil fuel-fired steam electric plants (one of the source categories in 52.21(b)(1)(i)(a) having a 100 tpy rather than a 250 tpy major source emission rate threshold) encompasses gas turbine combined cycle and cogeneration plants."[1] Note that the Power House facility contains two cogeneration units, and that the Power House and the Williams Village facility are considered a single source with respect to PSD requirements. Therefore, the combined source is subject to the 100 ton per year PSD thresholds.

Because combined potential emissions from the Power House and the Williams Village heating plant exceed 100 tpy each of CO, NO_x and SO_2, the facilities are considered a major stationary source with respect to these pollutants.

<u>40 CFR 60 Subpart Dc – Standards of Performance for Small Industrial-Commercial-Institutional Steam Generating Units</u>

Subpart Dc applies to units constructed, modified or reconstructed after June 9, 1989. The Williams Village boilers were in operation prior to this date. The facility obtained a significant modification to the operating permit on August 19, 2004 to allow for the addition of an economizer to boiler B001 and the replacement of an economizer for B002. Under 40 CFR §60.15(a) an existing facility becomes an affected facility, irrespective of any change in emission rate, upon reconstruction. "Reconstruction" means the replacement of components of an existing facility to such an extent that the fixed capital cost of the new components exceeds 50 percent of the fixed capital cost that would be required to construct a comparable entirely new facility (§60.15(b)). The source provided confirmation that the cost of the economizer project was significantly less than 50 percent of the cost to replace the boilers.

<u>40 CFR 63 Subpart DDDDD - National Emission Standards for Hazardous Air Pollutants for Industrial/Commercial/Institutional Boilers and Process Heaters</u>

The Power House/Williams Village facility is not a major source of Hazardous Air Pollutants (see Attachment 1); therefore Subpart DDDDD does not apply.

<u>Fuel Oil Sulfur Limits, SO_2 Limits and SO_2 Calculations</u>

The significant modification to the operating permit on August 19, 2004 included a new limit on the fuel oil sulfur content, as requested by the permittee (0.05 wt% Sulfur). The modified permit included the new limit, but did not address the fact that the existing supply of fuel in the tanks had a sulfur content of 0.105 wt% sulfur. Upon discovery of the discrepancy by the Division during a routine inspection, CU explained that they had understood the limit to apply to only future shipments of fuel oil, and demonstrated that based on the amount of fuel used, the SO_2 emission limits in the permit had not been exceeded. CU also demonstrated that based on a heat value of the existing fuel supply of 131,622 Btu/gallon, they were in compliance with the SO_2 standard of Regulation No. 1, Section VI.A.3.b.i (1.5 lb/MMBtu). An administrative modification was made to the permit on June 16, 2005 to state that the new fuel sulfur limits did not apply to the existing fuel supply, and to include the appropriate methods to demonstrate compliance

[1] See Memorandum from Edward J. Lillis, Permits Program Branch Chief to Bernard E. Turlinski (Region III) and George T. Czerniak (Region V), RE Determining Prevention of Significant Deterioration (PSD) Applicability Thresholds for Gas Turbine Based Facilities, dated February 2, 1993. (http://www.epa.gov/region7/programs/artd/air/nsr/nsrmemos/turbines.pdf)

with the Regulation No. 1 sulfur limit based on the emission factors and fuel heat values of the existing fuel supplies.

Since these modifications, there have been no new deliveries of fuel oil to the facility, and the boilers continue to operate using the 0.105 wt% sulfur supply. According to Division inspection reports, total fuel oil use was 593 gallons in 2007 and 1,748 gallons in 2008. The inspection completed on February 26, 2009 noted 11,685 gallons in the west tank and 3,994 gallons in the east tank.

The permit is currently set up to determine compliance with limits and to calculate emissions based on two separate scenarios: use of the existing fuel supply, and use of the new fuel supply, which is required to meet the 0.05 wt% sulfur requirement. There is no requirement to exhaust existing fuel supplies prior to receiving new shipments; therefore the possibility exists that new fuel might be added to existing fuel in the tanks, creating a mixture that does not have any corresponding compliance demonstration methods in the permit.

To address this scenario, the Division determined the maximum amount of existing fuel that would make a significant contribution to the sulfur content of a mixture of existing and new fuel (see Attachment 2). Specifically, if the amount of existing fuel is 1,800 gallons or less and new fuel is added to capacity (20,000 gallons), the sulfur content of the mixture is calculated to be 0.05 wt%, within rounding error. In this case, the resulting emission factor used to calculate SO_2 emissions and to determine compliance with the Regulation No. 1 emission factor is essentially the same as that for a completely new supply of fuel meeting the new sulfur limits. However, if more than 1,800 gallons of existing fuel are in the mixture, or if the tank is not filled to capacity, the new fuel emission factors may not adequately represent the mixture.

The permit conditions have been updated to account for the following scenarios:

- Prior to delivery of new fuel, the SO_2 emission factors shall be based on existing fuel characteristics
- After the first delivery of the new fuel, the SO_2 emission factors may be based on the new fuel sulfur limits if the delivery to each tank is 18,200 gallons or more. Otherwise, the sulfur content of the mixture must be calculated (the equation used to calculate the sulfur content of the mixture has been added to Appendix G)
- After the second delivery of the new fuel, any contribution to the mixture of the original existing supply is assumed negligible, and SO_2 emission factors may be based on the new fuel sulfur limits.

In order to show compliance with the Regulation No. 1 SO_2 limit, the SO_2 emission factor in lb/1000 gallons must be converted to lb/MMBtu by dividing by the heat content of the fuel. Since the heat content of the fuel oil for the existing supply is known (131,622 Btu/gal), compliance with the standard for the existing supply may be presumed (in absence of any credible evidence to the contrary). The previous issuance of the permit noted that compliance with the standard for the new fuel supply may also be presumed, based on an assumption that the heat content of the fuel is no less than

15,500 Btu/gal. Note that using the appropriate AP-42 factors, a sulfur content of 0.05 wt% and a heat content of 15,500 Btu/gal, the SO_2 emission factor is calculated to be 0.46, which is less than half the standard of 1.5 lb/MMBtu. The source of the 15,500 Btu/gal value is not explained; however, it does show compliance with the standard and the typical heat value of any new source of fuel oil should easily meet this heat value minimum. The language referencing the 15,500 Btu/gal value will therefore be retained in the renewal permit.

Alternative Operating Scenarios (AOS)

The previous permit included alternative operating scenarios that allow for the following: (1) Boiler B001 B002 may use No. 2 Fuel oil if natural gas is not available, and (2) a temporary boiler of heat input less than 10.044 MMBtu/hr and 10,000 pounds steam/hour may be used for less than 720 hours per year during maintenance and repair of boilers B001/B002.

During review of the draft permit, the source noted that the boilers should have the capability to fire on fuel oil at their discretion and not only during periods of fuel oil unavailability. The Division agrees that the permit limits are independent of the fuel used, and that no underlying requirement could be identified which would restrict the type of fuel used based on the availability of natural gas. Because the permit includes the applicable requirements during fuel oil combustion in Section II, Condition 2, this portion of the AOS has been removed.

The source also requested during review of the draft permit that the temporary boiler identified in the AOS be allowed to operate more than the specified 720 hours, and that it be allowed to provide more than 10,000 pounds of steam per hour. The purpose of the request was to address catastrophic failure of both boilers. Based on a file review, it appears that the 10,000 lb steam/hr and the 720 hour limits were requested by the source in a letter to the Division received March 17, 2004. In May, 2004 the source notified the Division of a temporary shutdown (approx. 1 month) of the main boilers in June 2004 to perform routine maintenance. The letter also stated that "UCB plans to separate the current common stack associated with these two boilers so that each boiler has its own individual stack. The purpose of separating the common stack is to avoid the necessity to shut down both boilers anytime routine maintenance or repair is required on just one of the boilers. This will also alleviate the need for a temporary boiler during annual maintenance activities."

It should be noted that the Division does not currently have a policy of including AOS provisions for temporary boiler replacements. The AOS previously included in the permit appears to be related to a specific unit that was operated at the facility in the past. The source confirmed that this unit is no longer on site at the facility, and may not be available to the facility in the future. The Division is therefore removing the AOS provisions related to this unit.

If the source wishes to permit a specific unit for use during planned maintenance activities, the Division will consider such a unit once it is identified. At this point in time, the Division does not include AOS provisions in operating permits to address catastrophic failure for boilers (such an event may qualify as a malfunction subject to the Common Provisions Regulation, or as an Emergency under the emergency provisions of Regulation No. 3, Part C, VII.E). Therefore, no AOS provisions are being carried into the renewal permit.

Compliance Status

The Division conducted a full compliance evaluation at the facility on February 26, 2009. The facility was in compliance with all terms of the Operating Permit at the time, except that the semi-annual monitoring and annual compliance reports due on January 1, 2009 were received on January 5, 2009. Since the reports have been submitted and the permit already contains a clear statement about the due date of such reports (see page following cover page), no additional changes with respect to the Operating Permit renewal are anticipated.

III. Discussion of Modifications Made

Source Requested Modifications

The renewal application received on July 27, 2007 did not request any changes to the existing operating permit. The source submitted a notification (received January 16, 2009) stating that the responsible official had changed, and submitted a new facility contact person on February 24, 2010. This information was included on the page following the cover page. The source provided an corrected facility address on March 25, 2010 which is also included on the page following the cover page.

Other Modifications

In addition to the source requested modifications, the Division has included changes to make the permit more consistent with recently issued permits, include comments made by EPA on other Operating Permits, as well as correct errors or omissions identified during inspections and/or discrepancies identified during review of this renewal.

The Division has made the following revisions, based on recent internal permit processing decisions and EPA comments, to the Williams Village Operating Permit. These changes are as follows:

Page Following Cover Page

- It should be noted that the monitoring and compliance periods and report and certification due dates are shown as examples. The appropriate monitoring and compliance periods and report and certification due dates will be filled in after permit issuance and will be based on permit issuance date. Note that the source may request to keep the same monitoring and compliance periods and report and certification due dates as were provided in the original permit. However, it should be noted that with this option, depending on the permit issuance date, the first monitoring period and compliance period may be short (i.e. less than 6 months and less than 1 year).

Section I – General Activities and Summary

- Updated Condition 1.1 to reflect the ozone nonattainment status of the area in which the facility is located
- Revised the language in Condition 1.4 to include current conditions that are state-only enforceable.
- Added a note to Condition 1.5 to state that either electronic or hard copy records are acceptable.
- Condition 2 allows a temporary boiler of 10.044 MMBtu/hr our less to operate for a maximum of 720 hours per year or less during maintenance of Boilers B001/B002. A new boiler greater than 10 MMBtu/hr is potentially subject to NSPS Dc requirements, depending on the date of construction. A new sub condition was added to state that the permittee shall comply with all applicable state and federal requirements with respect to any temporary boiler operation, which might include NSPS Dc, and Colorado Regulations No. 1 and 6 related to particulate matter, opacity and SO_2 limits.
- Updated Condition 3.1 to note that the source is a major stationary source with respect to non attainment new source review requirements (PTE of the Power House and Williams Village combined is greater than 100 tons per year of NO_x). The facility is also a major stationary source for PSD purposes because CO, NO_x and SO_2 potential to emit exceed 100 tons per year. Note that the previous permit stated a PSD threshold of 250 tpy; this has been corrected to 100 tpy as discussed above in the Applicable Requirements section.
- Condition 5 – Removed the Emission Unit Number column from the Summary of Emission Units (the facility identifier and the AIRS ID are the useful identifiers used by the Division and the facility).
- Condition 6 – updated the CAM condition to the Division's current standard language.
- Condition 2 – The Alternative Operating Scenarios from the previously issued permit have been removed (see discussion above for further details).

<u>Section II – Specific Permit Terms</u>

- Condition 2 – added a note to the table to emphasize that limits apply to each individual boiler.
- Condition 2.1 – the previous permit included emission factors for the boilers during natural gas consumption based on AP-42 emission factors (Chapter 1.4, July 1998). These AP-42 emission factors, which are based on a natural heating value of 1,020 Btu/scf, were adjusted downward slightly to correspond to a natural gas heating value of 1,000 Btu/scf. The source submitted an APEN on March 29, 2007 listing the heating value as 1,020 Btu/scf; therefore the emission factors listed in the renewal permit will be changed to the non-adjusted values from AP-42.

- Conditions 2.3, 2.4 & 2.5 – slight changes were made to the language describing the presumption of compliance with the PM and opacity standards during combustion of natural gas based on comments made by EPA on other recently issued operating permits.

- Condition 3.1 – The SO_2 emission factors have been moved to a new condition (3.8) to clarify the difference between existing and new fuel supplies, and to address the scenario of a potential fuel mixture. See the discussion above for further details.

- Condition 3.1 – The emission factors included for PM and PM_{10} in the previous permit are based on only the filterable portion of PM (the PM_{10} fraction is based on the cumulative particle size distribution of AP42 Table 1.3-6, September 1998). EPA has specified that PM-10 should include condensable particulate matter as well as filterable particulate matter (note that the emission factors for natural gas combustion elsewhere in the permit do include both filterable and condensable). Therefore, the condensable portion of the emission factor from AP42 has been added to the PM and PM_{10} emission factors listed for fuel oil in the renewal.

- Condition 3.2 – slight changes were made to the language describing the presumption of compliance with the PM standard during combustion of fuel oil based on comments made by EPA on other recently issued operating permits.

- Condition 3.3 – this condition has been updated to clarify the compliance demonstration methods for the Regulation No. 1 SO_2 standards (see discussion in Section II above for additional details).

- Conditions 3.6.1 and 3.7.1 – these conditions specified the visible emission observations required to monitor compliance with the opacity limit of Regulation No. 1 during fuel oil combustion. Reg No. 1 includes a 30% limit during certain activities, including startup and process modifications, and a 20% limit during all periods of operation not subject to the 30% limit. Condition 3.7.1 is intended to address periods of startup, and Condition 3.6.1 is intended to address periods not including startup. Both conditions specify that “startup” means a “cold startup” and does not apply to switching fuel during normal operations. The source questioned the purpose of this language during review of the draft permit, and noted that the boilers cannot switch fuels during operation (they must shutdown the boiler and physically switch the feed lines, then startup again). The Division is therefore removing the language defining startup. However, it can be noted that “periods of switching fuel during normal operations” likely qualify as “process modifications” subject to the same 30% opacity requirement that applies to a “cold startup,” and therefore the startup definition is not correct even in the event that fuel switching was possible for this facility.

<u>Section III – Permit Shield & Streamlined Conditions</u>

- The regulatory citation at the beginning of Section III was corrected.

- The Section 112(j) statement in the non-applicable requirements section was deleted as there are not currently any un-promulgated NESHAPS that could apply to the facility.

- Added a new Condition 3 to Section III to address streamlined/subsumed conditions (no conditions are streamlined at this time)

Section IV – General Permit Conditions

- Updated the general permit conditions to the current version (7/21/2009).

Appendices

- Added the site location map submitted with the renewal application to Appendix A.

- Corrected the volume of the fuel oil tanks from 24,000 gallons to 20,000 gallons, based on a Division inspection report dated February 26, 2009.

- Updated Appendices B and C (Monitoring and Permit Deviation Reports and Compliance Certification Reports) to the newest versions (2/20/2007).

- EPA's mailing address was revised (Appendix D).

- Cleared the list of Permit Modifications in Appendix F

ATTACHMENT 1 – FACILITY EMISSION CALCULATIONS

Potential to Emit: B001 & B002 (both Williams Village Boilers combined)

Pollutant	Emission Factor[1]		Emissions based on Max Assumed Fuel Use[2]		Max PTE[3]
	Natural Gas (lb/MMscf)	Distillate Oil (lb/Mgal)	Natural Gas	Distillate Oil	ton/yr
CO	84	5	27.8	12.8	27.8
VOC	5.5	0.2	1.8	0.5	1.8
PM	7.6	3.3	2.5	8.5	8.5
PM10	7.6	1.65	2.5	4.2	4.2
NOx					43.0
SO2					47.0

HAP Potential to Emit: B001 & B002 (both Williams Village Boilers combined)

Pollutant	Emission Factor[1]		Emissions based on Max Assumed Fuel Use[2]		Max PTE[3]
	Natural Gas (lb/MMscf)	Distillate Oil (lb/Mgal)	Natural Gas	Distillate Oil	lb/yr
Benzene	2.10E-03	2.14E-04	1	1	1
Ethylbenzene		6.36E-05	0	0	0
Formaldehyde	7.50E-02	3.30E-02	50	169	169
Naphthalene	6.10E-04	1.13E-03	0	6	6
Toluene	3.40E-03	6.20E-03	2	32	32
Xylenes		1.09E-04	0	1	1
TOTAL					**209**

Notes

1. Emission factors are from AP42, Chapter 1.3 (9/1998) for fuel oil combustion, and 1.4 (7/1998) for natural gas combustion. PM10 emissions from distillate oil are assumed to be 50% of PM based on AP42 Table 1.3-6.
2. Emissions for each fuel type are calculated based on an assumed maximum fuel consumption (i.e., combined boiler heat input of 77 MMBtu/hr, and assuming a natural gas heat value of 1020 btu/scf and a fuel oil heating value of 131,622 btu/gal (from the APEN received on 3/29/2007), and assuming operation of 8760 hours per year on each fuel type).

3. PTE is assumed to be the higher of the values calculated for each fuel type (except for NOx and SO2, which are the permitted limits). Note that only formaldehyde exceeds APEN reportable thresholds at the Maximum Assumed Fuel Use.

POWER HOUSE EMISSION CALCULATIONS

Potential to Emit: HAPs for TU001 & TU002 (combined)

Pollutant	Emission Factor (lb/MMBtu)[1] Natural Gas	Emission Factor (lb/MMBtu)[1] Distillate Oil	Emissions based on Permitted Fuel Use[2] Natural Gas	Emissions based on Permitted Fuel Use[2] Distillate Oil	Max PTE[3] lb/yr
Lead		1.40E-05	0	3	3
Acetaldehyde	4.00E-05		111	0	111
Formaldehyde	7.10E-04	2.80E-04	1970	52	2023
Propylene Oxide	2.90E-05		80	0	80
Manganese		7.90E-04	0	148	148
TOTAL					**2365**

Notes

1. Emission factors are from AP42, Chapter 3.1 (4/2000)
2. Emissions for each fuel type are calculated based on maximum permitted fuel use for each individual fuel type (2775 MMscf/year for natural gas, 1,430,000 gal/year for oil). Fuel heat values are assumed to be 1,000 btu/scf for natural gas and 130,854 btu/gal for fuel oil, based on values submitted on APENs received on 12/10/2009
3. PTE is the total emissions from both permitted fuels. HAPs included in the table above are those where Max PTE exceeds APEN reportable thresholds.

Potential to Emit: HAPs for DU001 & DU002 (combined)

Pollutant	Emission Factor[1] Natural Gas (lb/MMscf)	Emission Factor[1] Distillate Oil (lb/Mgal)	Emissions based on Permitted Fuel Use[2] Natural Gas	Emissions based on Permitted Fuel Use[2] Distillate Oil	Max PTE[3] lb/yr
Lead	0.0005		0	0	0
Benzene	2.10E-03	2.14E-04	1	0	1
Ethylbenzene		6.36E-05	0	0	0
Formaldehyde	7.50E-02	3.30E-02	30	10	40
Naphthalene	6.10E-04	1.13E-03	0	0	1
Toluene	3.40E-03	6.20E-03	1	2	3
Xylenes		1.09E-04	0	0	0
TOTAL					44

Notes

1. Emission factors are from AP42, Chapter 1.3 (9/1998) and 1.4 (7/1998).
2. Emissions for each fuel type are calculated based on maximum permitted fuel use for each individual fuel type (400 MMscf/year for natural gas, 288,000 gal/year for oil).
3. PTE is the total emissions from both permitted fuels. Note that no HAPs exceed APEN reportable thresholds at the permitted fuel limits.

Potential to Emit: HAPs for B003 & B004 (combined)

Pollutant	Emission Factor[1] Natural Gas (lb/MMscf)	Emission Factor[1] Distillate Oil (lb/Mgal)	Emissions based on Permitted Fuel Use[2] Natural Gas	Emissions based on Permitted Fuel Use[2] Distillate Oil	Max PTE[3] lb/yr
Lead	0.0005		0	0	0
Benzene	2.10E-03	2.14E-04	1	0	1
Ethylbenzene		6.36E-05	0	0	0
Formaldehyde	7.50E-02	3.30E-02	50	6	56
Naphthalene	6.10E-04	1.13E-03	0	0	1
Toluene	3.40E-03	6.20E-03	2	1	3
Xylenes		1.09E-04	0	0	0
TOTAL					62

Notes

1. Emission factors are from AP42, Chapter 1.3 (9/1998) and 1.4 (7/1998).

2. Emissions for each fuel type are calculated based on maximum permitted fuel use for each individual fuel type (660 MMscf/year for natural gas, 193,000 gal/year for oil).
3. PTE is the total emissions from both permitted fuels. Note that only formaldehyde exceeds APEN reportable thresholds at the permitted fuel limits.

Power House Facility-Wide Potential to Emit (HAPs)

	Formaldehyde[1] (tons/year)	Total HAP[2] (tons/yr)
TU001 & TU002	1.01	1.18
DU001 & DU002	NA	NA
B003 & B004	0.03	0.03
TOTAL	**1.04**	**1.21**

Notes

1. Highest Single HAP

2. HAPs included for each point are those where emissions at the maximum permitted fuel use exceed APEN reportable thresholds.

Potential to Emit: Williams Village & Power House Combined

Pollutant	Power House[2]	Williams Village[3]	TOTAL
NOx	Less than 250	43.0	Less than 293
CO	90	27.8	117.8
VOC	62.6	1.8	64.4
SO2	56.7	47.0	103.7
PM	24.2	8.5	32.7
PM10	24.2	4.2	28.4
Formaldehyde[1]	1.04	0.1	1.1
Total HAPs	1.21	0.1	1.3

Notes

1. Highest Single HAP

2. PTE for criteria pollutants are based on permit limits (PM10 is assumed to be equal to PM). See detail for Power House emission units for HAP PTE calculations (above)

3. See detail for Williams Village Boilers for HAP and Criteria PTE calculations (above)

ATTACHMENT 2: CALCULATION OF THE FUEL SULFUR CONTENT OF NO. 2 FUEL OIL FROM TWO SEPARATE SOURCES

Existing fuel oil Sulfur content: 0.105 wt%
New fuel oil Sulfur content (permit-limited): 0.05 wt%
Total capacity of each fuel tank: 20,000 gallons
Density of Fuel Oil: 7.05 lb/gal (assumed to be density of Distillate Oil, AP42, Appendix A, 9/1985)

$$\text{Sulfur in Mixture (lb)} = 7.05\ \text{lb/gal} \times \left(\text{Existing Fuel Volume} * (0.00105) + \text{New Fuel Volume} * (0.0005)\right)$$

$$\text{Weight Fraction of Sulfur in Mixture} = \frac{\text{Sulfur in Mixture (lb)}}{20{,}000\ \text{gallons} \times \frac{7.05\ \text{lb}}{\text{gallon}}}$$

When existing fuel volume = 1,800 gallons and new fuel volume = 18,200 gallons, the weight fraction of sulfur in the mixture is 0.0005, or 0.05 wt%.

ATTACHMENT 3 – RULE VERSION DATES

This Technical Review Document considers applicability and requirements from rules and regulations at the time the renewal permit was drafted. The version dates of these rules and regulations are listed in the following table:

Rule/Regulation	**Version Date**
Colorado Regulation No. 1	Amended 6/21/07, effective 8/30/07
40 CFR 63 Subpart DDDDD	December 6, 2006*
40 CFR 60 Subpart Dc	January 28, 2009

*vacated and remanded on June 8, 2007